RESEARCH REPORT 85-1

ESTIMATED PETROLEUM FINDING COSTS IN ALBERTA 1970-1983

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CONTENTS

FIGURES v

TABLES vii

PREFACE ix

EXECUTIVE SUMMARY xi

CHAPTER 1 INTRODUCTION 1

1.1 Background 1

1.2 Objectives 1

1.3 Methodology and Assumptions 2

1.4 Study Organization 2

CHAPTER 2 METHODOLOGY AND ASSUMPTIONS 5

2.1 Some Methodological Problems 5

2.2 Definitions and Assumptions 6

2.2.1 Finding Cost 6
2.2.2 Crude Oil Equivalency 8
2.2.3 Reserve Appreciation 8
2.2.4 Calculating Separate Oil and Gas Finding Costs 9
2.2.5 Finding Costs with Time-Lagged Expenditures 10
2.2.6 Replacement Cost of Reserves 10

2.3 Limitations of the Results 11

2.4 Comparison of Results 12

CHAPTER 3 EXPENDITURES AND RESERVES DATA AND CRUDE OIL EQUIVALENT FINDING COSTS 15

3.1 Expenditures and Reserves Data 15

3.1.1 Expenditures 15
3.1.2 Reserves 15
3.1.3 Data Qualifications 16

3.2 Basecase Finding Costs 16

3.3 Finding Cost Sensitivity Cases 18

3.3.1 Higher Reserves Appreciation 18
3.3.2 No Reserves Appreciation 19
3.3.3 Prorated Land and Rental Expenditures 19
3.3.4 Crude Oil Equivalence Conversion 19
3.3.5 Alternative Reserves Data Source 19
3.3.6 Summary 21

CHAPTER 4 SOME EXTENSIONS TO THE BASECASE ANALYSIS 23

4.1 Introduction 23

4.2 Separate Crude Oil and Natural Gas Finding Costs 23

4.3 Finding Costs with Time-Lagged Expenditures 25

4.4 Reserves Replacement Costs 25

4.5 Further Extensions to the Analysis 29

CHAPTER 5 SUMMARY AND CONCLUSIONS 31

5.1 Finding Cost Results 31

5.2 Policy Implications 33

APPENDIX A CRUDE OIL AND NATURAL GAS RESERVES APPRECIATION 35

APPENDIX B EXPENDITURES AND RESERVES DATA AND CRUDE OIL EQUIVALENT FINDING COSTS 39

APPENDIX C RESULTS OF EXTENDED ANALYSES 51

BIBLIOGRAPHY 61

FIGURES

3.1 Alberta Finding Costs: 1970-1983 17

3.2 Alberta Finding Cost Sensitivity Cases: 1970-1983 20

4.1 Intent Estimation for Alberta Exploration Activity: 1970-1983 24

4.2 Alberta Crude Oil and Natural Gas Finding Costs: 1970-1983 26

4.3 Alberta Lagged Expenditures Finding Costs: 1970-1983 27

4.4 Alberta Oil and Gas Reserves Replacement Costs: 1970-1983 28

TABLES

2.1	Definitions and Assumptions	7
5.1	Summary of Alberta Finding Cost Results: 1970-1983	32
A.1	Alberta Crude Oil Reserves Appreciation, 1970-1983	37
A.2	Alberta Natural Gas Reserves Appreciation, 1970-1983	38
B.1	Alberta Net Cash Expenditures, 1970-1983	41
B.2	CPA Cost Escalation Indices by Expenditure Type, 1970-1983	42
B.3	Alberta Crude Oil, Pentanes Plus, Natural Gas Liquids, and Marketable Natural Gas Initial Established Reserves, 1970-1983	43
B.4	Alberta Finding Costs, 1970-1983	44
B.5	Alberta Finding Costs by Expenditure Type, 1970-1983	45
B.6	Sensitivity One: Higher Reserves Appreciation	46
B.7	Sensitivity Two: No Reserves Appreciation	47
B.8	Sensitivity Three: 50 Percent of Land Expenditures	48
B.9	Sensitivity Four: Energy Equivalence Conversion	49
B.10	Alberta Crude Oil Finding Costs, 1970-1983	50
C.1	Intent Estimation For Alberta Exploration Activity, 1970-1983	53
C.2	Alberta Crude Oil Finding Costs: Estimated Intent Only, 1970-1983	54
C.3	Alberta Natural Gas Finding Costs: Estimated Intent Only, 1970-1983	55
C.4	Alberta Crude Oil Finding Costs: Estimated Oil Intent + 15%, 1970-1983	56
C.5	Alberta Natural Gas Finding Costs: Estimated Oil Intent + 15%, 1970-1983	57

C.6 Alberta Lagged Expenditures Finding Costs, 1970-1983 58

C.7 Long-Term Bond/Industrials Yield Index, 1970-1983 59

C.8 Alberta Crude Oil and Natural Gas Reserves Replacement Costs, 1970-1983 60

PREFACE

The authors would like to express their gratitude to the advisory committee of industry, industry association, and government representatives who provided assistance and direction at the initial stages of the study, and valuable comments on the final draft. Special mention is also due to many other industry and government officials who contributed substantially to the quality and depth of the study. However, the authors themselves are solely responsible for the conclusions drawn, and for any errors or omissions which remain.

Many thanks go to Brian Cox and Adele Crowley for the computer programming which serves as the backbone of the study. The excellent word processing of Shirley Ingstrup, Megan McCarthy, and Jan Morrison, as well as the precise graphics work of Doug Gillett and Donna Peterson, are also much appreciated.

EXECUTIVE SUMMARY

The prime objective of this research report is to provide estimates of petroleum finding costs for the Province of Alberta during the period of 1970 to 1983.

The methodology employed and the primary results are summarized as follows:

Definitions and Assumptions

- The cost of finding a unit of crude oil or equivalent is defined as the ratio of exploratory expenditures in a given year to reserves discovered in the same year, fully appreciated to the year of discovery.

- Initial discoveries of crude oil, pentanes plus, NGL, and natural gas are multiplied by reserve appreciation factors of 3.20 for crude and 3.28 for pentanes plus, NGL, and natural gas. These factors were derived from historical reserves data. Appreciation accounts for revisions, extensions, and other activities which contribute to the delineation of the true size of the discovery.

- Natural gas reserves are converted to crude oil equivalence based on an historical price relationship of 10.5 Mcf to 1 barrel of crude. Pentanes plus and NGL are added on a one-to-one basis. Sulphur reserves are excluded from the analysis.

Basecase and Sensitivity Cases: Results

- Fluctuations in yearly finding costs are primarily due to corresponding swings in the amount of reserves discovered in each year. The trend shown by the 3-year moving average finding costs, however, parallels more closely the trend in exploratory expenditures. The general trend is rising to 1981 followed by a slight decline. The 5-year and 7-year moving averages indicate a definite rising trend.

- In the sensitivity analyses, the largest impact on the basecase results occurs with changes in the reserves appreciation rate. This suggests that reserves data and appreciation rates are critical in calculating and interpreting oil finding cost results.

- Three-year moving average basecase and sensitivity case finding costs for 1983 are summarized in the following table (in 1983$ per BOE):

	Sensitivity Cases			
Basecase	Higher Reserves Appreciation	No Reserves Appreciation	50% Land Expenditures	Energy Equivalence Conversion
10.50	6.00	33.80	9.00	7.90

Extensions to the Analysis

- Separate crude oil and natural gas finding costs are calculated by estimating the intent of exploration on the basis of successful exploratory drilling footage. Using this measure of intent, total exploration expenditures are allocated to crude oil and natural gas.

- Finding costs are also calculated with land expenditures and geological and geophysical expenditures lagged two years and one year, respectively, to account for the time pattern of exploratory expenditures.

- Replacement or booking costs, defined as the cost of replacing reserves in the ground, are calculated for Alberta by adding average yearly development costs and finding costs.

- Three-year moving average results for selected years for these three extensions to the analysis are summarized in the following table:

	Finding Costs				
Year	Basecase ($/BOE)	Crude ($/bbl)	Natural Gas ($/Mcf)	Lagged Expenditures ($/BOE)	Replacement Costs ($/BOE)
1972	4.90	4.60	0.50	NA	10.20
1976	8.40	24.30	0.70	8.80	13.20
1980	11.80	10.70	1.20	11.30	16.50
1983	10.50	7.80	1.30	15.90	16.40

Conclusions and Caveats

- The results of this analysis must be interpreted within the context of the methodology and assumptions provided. Direct comparisons with other studies on finding costs are generally not possible due to differences in methodology, data bases, and assumptions. The results provide an industry "yardstick" against which to compare individual company results rather than the final word on actual finding costs in Alberta.

- Our main conclusion is that Alberta finding costs for both crude oil and natural gas are generally increasing. This trend is confirmed by results obtained when oil and natural gas finding costs are separated and when land costs and geological and geophysical costs are lagged to account for the time phasing involved in the exploratory process.

Implications for Government Policy

- The public policy implications of the research results reported here are fairly clear in spite of the limitations inherent in the data used and the scope of the study. As finding cost is an important part of the full-cycle cost of producing oil and natural gas, unless development and production costs are declining enough to offset the effects of increasing finding costs, the full-cycle cost must be rising over time. This and the outlook for oil and natural gas markets suggest that lower tax or royalty payments may be required in order to maintain the economic attractiveness of petroleum exploration in the future.

- This conclusion assumes that it is preferable from the viewpoint of social benefit/cost analysis to continue domestic exploration and production of petroleum rather than to increase Canadian reliance on imports which may prove cheaper during certain time periods.

Chapter 1

INTRODUCTION

1.1 Background

A number of studies and research reports have recently been published on the subject of crude oil and natural gas finding costs in both Canada and the U.S.[1] The question of how much it costs a company--or the whole industry--to find additional hydrocarbons is particularly relevant since the pools being discovered are generally smaller, the industry has largely been deregulated, and the world price of oil is under considerable downward pressure. This provides for a difficult situation for the explorationists who, while facing a rising cost of finding crude oil and natural gas, are also confronted with a considerable downsize risk potential on the selling price. The issue of finding costs is also very important to governments in estimating the appropriate level of taxes and royalties designed to capture the so-called economic rent generated during the production of petroleum.

Some of the recent studies of finding costs have provided a good analytical background and discussion of the methodological issues involved. However, there is still a lack of actual finding cost estimates, especially for the most recent period and separated between oil and gas.

1.2 Objectives

The prime objective of this research report is to provide estimates of petroleum finding costs for the Province of Alberta during the period of 1970 to 1983. Finding costs are estimated on a per barrel of crude oil equivalent basis but a framework for splitting oil and gas is also provided. In addition, a further step towards estimating the overall profitability of the oil and gas production cycle is examined by providing some estimates of reserves replacement costs.

The overall intention is not to offer an exhaustive discussion of all the methodological issues involved in calculating finding costs or to provide the "final word" on finding cost estimates. Rather, a

methodology utilizing publicly available data to calculate finding costs is offered for discussion.

1.3 Methodology and Assumptions

Conceptually, calculating the finding cost of oil and gas is a very simple problem: divide the cost of searching for reserves by the amount of reserves discovered. However, problems arise immediately in estimating either the numerator (exploration costs) or the denominator (reserves found) of the above ratio. Data published by the Canadian Petroleum Association (CPA) are utilized for both exploration expenditures and reserves discovered to arrive at average annual provincial finding costs on a per barrel of oil equivalent basis. Natural gas, pentanes plus, and natural gas liquids (NGL) are all translated into crude oil equivalents. On the basis of the same data source, reserves appreciation rates are calculated which are used to fully appreciate annual initial discoveries. A basecase plus five sensitivity analyses are presented.

A method based on the ratio of successful oil to total successful exploratory drilling is suggested to split oil and gas exploration expenditures which permits separate estimates of finding costs for crude oil and natural gas. Data on development expenditures are also used to calculate the cost of replacing petroleum reserves in the ground.

1.4 Study Organization

The study is organized as follows. First, Chapter 2 presents the necessary details on definitions and assumptions such that the results contained in this publication can be duplicated, as well as some comments on the appropriateness of the methodology used. Chapter 3 presents the expenditures and reserves data, and the results of the basecase and sensitivity analyses. Some extensions to the present work are given in Chapter 4. Oil and gas exploration expenditures are split to calculate separate finding costs for both products, finding cost results using time-lagged expenditure variables are presented, and reserves replacement costs are estimated. Chapter 5 provides a summary and conclusions.

Footnotes

[1]See for instance, P. Eglington and M. Uffelman, Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979, Discussion Paper No. 235 (Ottawa: Economic Council of Canada, August 1983); or various studies undertaken by the industry, industry associations, and governments. The latter, however, have often been produced only for internal use.

Chapter 2

METHODOLOGY AND ASSUMPTIONS

2.1 Some Methodological Problems

As mentioned above, calculating crude oil or natural gas finding costs is a simple arithmetic exercise. Some difficulties arise, however, in collecting available data on both the expenditures associated with discovering reserves and the size of the reserves discovered.

There are three basic problems inherent in a study of petroleum finding cost. The first problem is to estimate the reserves discovered as a result of given exploratory expenditures. While certain amounts of petroleum reserves may be found in a given year, this amount is usually revised in subsequent years. Over time, through these revisions (appreciation), the total amount of the original "discovery" is ascertained. A certain amount of professional judgement and, hence, subjectivity is involved in estimating the size of oil and gas reserves in the ground. The accuracy of any reserve appraised will be a function of the amount and quality of the geophysical, geological, and engineering data available, and the interpretation of such data. It is, therefore, not unusual to observe discrepancies in reserve estimates provided by different sources. For the purposes of this study, Canadian Petroleum Association (CPA) initial established reserves data are used, fully appreciated back to the year of discovery.

The second problem is that of properly estimating the expenditures associated with finding oil and gas. Several kinds of cost must be included: (i) the cost of land acquisition and land rentals; (ii) geological and geophysical costs; and (iii) the cost of drilling a well. These are usually grouped together under "exploration costs." Published exploration cost data exist but only in an aggregate form for oil, natural gas, and other hydrocarbons combined. Thus, a problem arises in estimating the finding cost of oil and natural gas separately. A statement of intent for each well drilled as well as a methodology to allocate the cost of discovering a product other than the one intended would be required to properly allocate the cost of exploration between the two products. Such information simply does not exist, expecially in areas where both oil and gas reserves occur. One way to resolve this problem

is to calculate the finding cost on a per unit of oil equivalent basis. All other hydrocarbons discovered (natural gas, pentanes plus, and NGL) are simply translated into oil equivalent on the basis of either their relative price or heating content. If separate finding costs for oil and gas are desired, a method must be designed to approximate the intent of exploratory expenditures. One such possibility is suggested in Chapter 4.

The third basic problem inherent in an oil finding cost study is that of synchronizing the finding expenditures with discoveries. There could be several years between exploration and development expenditures and discoveries, and the proving or "booking" of reserves in the ground. Although the process of compounding can be used to account for expenditures in different time periods, the difficulty of properly estimating and relating the exploratory and development phases of establishing petroleum reserves remains. Chapter 4 presents finding cost estimates based on time-lagged data.

To deal with some of these and other related difficulties of the analysis, a "basecase" set of finding costs is calculated and then some of the assumptions are altered to test the sensitivity of the basecase results to changes in critical variables. Table 2.1 outlines some of the definitions and assumptions fundamental to this analysis.

2.2 Definitions and Assumptions

2.2.1 Finding Cost

For the purpose of this study, finding cost is defined as the ratio of exploratory expenditures of a given year divided by reserves discovered in the same year, fully appreciated to the year of discovery.[1] Fully appreciating reserves to the year of discovery is an attempt at the "actual" size of the discovery and, thus, at the "true" estimate of finding cost. In terms of the CPA data used, exploration expenditures include geological and geophysical costs, drilling costs and the cost of land acquisition and rentals. All cost data are translated into 1983 dollars using CPA's cost indices. For discoveries, data on initial established reserves by year of discovery are used.

Other definitions of finding cost can also be used. One possibility is to define it as the ratio of exploration and development expenditures to discovered and developed reserves. Using this definition, however, creates at least two additional problems: (i) the timing and

TABLE 2.1

DEFINITIONS AND ASSUMPTIONS

Term	Definition	Calculated/Estimated As
Finding Cost	Total exploration costs in a given year divided by fully appreciated reserves discovered in that year.	Total Exploration Expd. / Crude + NGL + Natural Gas Reserves x Appreciation rate
Reserves Apppreciation Rate	The amount by which initial petroleum reserves discoveries are expected to increase over time.	Crude Oil = 3.20 Natural Gas, Pentanes Plus, and NGL = 3.28
Crude Oil Equivalence	The rate at which natural gas, pentanes plus, and NGL are converted to a crude oil basis.	Natural Gas: (1) Price Equivalence: 10.5 Mcf = 1 barrel (2) Energy Equivalence: 6 Mcf = 1 barrel Pentanes Plus and NGL: 1 barrel = 1 barrel of oil
Exploratory Intent (Oil)	The percentage of total exploratory activity attributable to finding oil.	Total Successful Oil Footage / Total Successful Exploratory Footage
Replacement Cost	The cost of replacing existing reserves in the ground. Also called "booking cost."	Finding Cost in a Given Year + Average Development Cost for that year

expenditure allocation between the exploratory and development processes becomes a source of disagreement and error (development costs, for example, tend to be much more site-specific); and (ii) not all development costs are incurred for the purpose of discovering (or proving) new reserves--some are a result of maintaining producibility rather than adding to new reserves (e.g., natural gas plants, other field capital outlays, reservoir pressure maintenance, etc.). It should also be noted that at times, different definitions of oil and gas finding costs have been used simply to suit the available expenditures and reserves data.

The above simple definition of finding cost is preferable. However, more important than the definition per se is the use to which the results of such calculations are put. It is of critical importance that those who will use the results of this or other studies understand what these results mean.

2.2.2 Crude Oil Equivalency

It has been mentioned above that provincial finding cost averages include all hydrocarbon reserves discovered, not just those of crude oil.

Natural gas reserves are added to crude oil reserves on a 10.5 Mcf:1 bbl ratio basis. This ratio was derived by comparing average natural gas and crude oil prices over an 11-year period (1972-1983) using Alberta Energy Resources Conservation Board (ERCB) data. Given that no "correct" method exists for converting natural gas to crude oil equivalence, in one of the sensitivity cases, natural gas reserves are translated into crude oil equivalent using a 6 Mcf:1 bbl ratio reflecting the energy content of the two products.

Pentanes plus and natural gas liquids reserves are added to total crude and equivalent reserves on a 1:1 ratio basis with crude oil. Sulphur reserves have not been included in the analysis.

2.2.3 Reserve Appreciation

Reserve appreciation is the process by which the true size of an original discovery is ascertained through time. Without future reserve changes properly accounted for, any estimate of petroleum finding cost would be overstated. A method of calculating reserve appreciation has first been described by Arrington.[2] In order to calculate appreciation

rates we require data on initial discoveries and the first, second, etc. year's reserve revisions. The factor indicating the first year's growth of reserves following the year of discovery is then equal to the sum of all first-year reserves estimates over time (1971-1983 in our case) divided by the sum of initial annual discoveries (1970-1982). The second year's growth is then calculated by dividing the sum of second-year reserves estimates divided by first-year reserves estimates, and so on. The annual growth factors are then compounded to arrive at the total appreciation rate over time ("the appreciation").

Appreciation rates for both crude oil and natural gas are derived in Appendix A using this method and CPA reserves data for the years 1970 to 1983. The rates are 3.20 and 3.28 for oil and gas, respectively. Pentanes plus and natural gas liquids are appreciated at the same rate as natural gas. These figures are used in the basecase finding cost calculations and are changed for two of the sensitivity analyses.

2.2.4 Calculating Separate Oil and Gas Finding Costs

Annual provincial averages for crude oil equivalent finding costs have only limited usefulness. As mentioned above, separating the cost of finding between the two products requires either a statement of exploration intent or an estimate of it. As the former is practically impossible to obtain on a province-wide basis, the latter is used.

There are several proxies which could be used for exploration intent. One possible way explored in Chapter 4 is an extension of the typical assumption that if a company finds oil (gas), it was looking for oil (gas).[3] A logical extension of this argument is to assume that the actual ratio of a given company's oil versus gas successful exploratory wells to total successful exploratory wells approximates the "intent" for the purpose of allocating the company's total exploration expenditures between crude oil and natural gas. This, then, assumes that the percentages of dry holes allocated to oil and gas correspond to those of successful wells. This procedure can also be followed using footage rather than wells drilled to estimate intent. When this is done on a provincial basis, we can allocate exploratory expenditures to both products and calculate finding costs separately. In order to account for the greater risks inherent in exploring for oil, separate finding costs are also calculated on the basis of estimated intent increased by 15 percent in favor of oil expenditures.

2.2.5 Finding Costs with Time-Lagged Expenditures

To account for the timing of land, geological and geophysical, and drilling expenditures, finding costs can be calculated by acknowledging that some of these outlays are made in years prior to the discovery year.

To illustrate this methodology, crude oil equivalent finding costs are calculated using 2-year lagged land expenditures and 1-year lagged geological and geophysical expenditures,[4] employing the following formula:

$$FC_t = \left[LC_{t-2} \times \left(1 + r_{t-2}\right)^2 + GG_{t-1} \times \left(1 + r_{t-1}\right) + DR_t \right] \div ARES_t$$

where: FC_t = finding cost at time period t
LC = land and rental costs
GG = geological and geophysical costs
DR = the cost of drilling
ARES = fully appreciated reserves
r = the cost of money

The results are shown in Chapter 4.

2.2.6 Replacement Cost of Reserves

The cost of finding petroleum is only one part of the full-cycle production cost. To obtain a unit of crude oil or natural gas, we must find it, develop it and bring it to the surface, or produce it. The so-called "full-cycle" analysis of petroleum production takes into consideration all three stages. The "half-cycle" analysis usually involves the exploration phase on the one hand, and the development and production stages on the other.

In addition to the full and half-cycle analysis of petroleum production, we can define replacement or "booking" cost as the cost of replacing the inventory of oil and gas production--the reserves--in the ground, without producing it. Replacement cost is then defined as the cost of finding and developing reserves of either crude oil or natural gas.[5] The results are presented in Chapter 4.

2.3 Limitations of the Results

It is absolutely essential that the reader understands the limitations of the results presented in this study. The basecase presents provincial yearly average finding costs for all reserves discovered. These results can best be interpreted as a yardstick with which companies can compare their own finding costs to see how well they have done in discovering oil-equivalent reserves. The results could also be used to identify the trend over time of finding costs for the whole industry. The figures given must be interpreted strictly in the light of the assumptions and methodology outlined. Although the results are presented in dollars and cents, distinctions should not be made to two decimal points of precision.

It is possible that the results are somewhat overstated. During the 1970s, a good deal of gas reserves were discovered and a large number of wells may have been classified as exploratory rather than being more properly categorized as delineation or step-out wells. This has the effect of biasing total exploratory expenditures upward. In the basecase, the overall finding cost of oil equivalent may thus be overstated. By the same logic, when separate finding costs are shown between oil and gas, exploratory expenditures are biased towards gas, likely overstating natural gas finding costs and understating those of crude oil. Finally, excluding sulphur reserves also has a tendency to bias the results upwards.

Caution is also required in attempts to use the results to extrapolate future values of finding costs since the costs calculated here may not correspond to the industry's long-run supply curve. This is primarily due to the stochastic nature of the exploration process which means that the calculated finding costs may be above or below expected values of discovered reserves, possibly for an extended period of time.[6]

Results for separate crude oil and natural gas finding costs are more useful than the basecase results since they are more specific. However, all the other above limitations still apply to them. Separate oil and gas finding costs are more meaningful since they identify the cost estimates for the actual targets of the exploratory process.

2.4 Comparison of Results

Quick comparisons should not be made between the results of this study and those of other reports. Before any comparison is made, it must be realized what exactly is being compared. It is possible that a direct comparison cannot be made as either the definitions of finding (or replacement) costs differ between reports, or data sources (and, thus, the actual data) are not the same. Should any of these conditions apply, one would not be comparing "apples with apples."

This is, in fact, the case when comparing the results of this analysis with either the annual review of Canadian oil finding costs published by Oilweek,[7] or the results contained in a recent study by the Economic Council of Canada.[8]

The results of this study are not directly comparable with those of Oilweek because, although both calculations use CPA data for reserves and expenditures, critical assumptions and definitions differ. Oilweek's "finding cost" covers all of Canada (onshore and offshore) and all reserves, including sulphur, as "gross" reserves additions. On the expenditure side, both exploration and development costs are included. The present analysis of finding cost is on a provincial basis and excludes both sulphur reserves and development costs. Oilweek's "discovery cost" is defined as exploratory costs divided by unappreciated reserves discovered, as opposed to fully appreciated reserves in this analysis. Thus, neither the "finding cost" nor the "replacement cost" found herein are directly comparable with the results published by Oilweek.

It is also impossible to make a direct comparison of the results of this analysis with those published by the Economic Council of Canada (ECC). To begin with, the ECC uses CPA expenditures data but ERCB reserves data. It is important to note that the two sources of reserves data do not agree, for some years by a substantial amount. In addition, there are the following differences between the assumptions used by the ECC and those of this study: (i) in the ECC report, all cost variables except development cost are time-lagged; in this analysis only land costs and geological and geophysical costs are lagged, and then only as an extension to the basecase analysis; (ii) the definitions of "finding cost" are not the same as the ECC report analyses "booking cost," which includes development drilling as well as exploration expenditures; and (iii) the two analyses use different ways of appreciating reserves discovered: ECC uses unappreciated (ERCB) data for "Additions to

Established Reserves of Conventional Crude Oil" (which includes new discoveries, development and re-evaluation, and EOR); this analysis uses CPA reserves data for crude oil and equivalent: "Initial Established Reserves in Canada by Year of Discovery," fully appreciated back to the year of discovery using a derived appreciation rate.

For these reasons, direct comparisons cannot be made between the results of this study and those of the two reports cited. Comparisons with other available reports or internal analyses should always be preceded by a careful consideration of the definitions and assumptions used.

Footnotes

[1]Finding costs are forced to a zero value for years in which no reserves were discovered.

[2]See J. R. Arrington, "Predicting the Size of Discoveries is Key to Evaluating Exploration Programs," Oil and Gas Journal, February 29, 1960, pp. 130-135; R. E. Megill, "Problems in Estimating the Cost of Finding Oil and Gas," World Oil, May 1981, pp. 171-174; and Alberta Energy Resources Conservation Board, "Gas Reserves Trends," December 31, 1984.

[3]It should be noted that a discovery of both oil and gas is classified as an oil find.

[4]The lag times selected are arbitrary insofar as actual expenditure patterns vary considerably among companies and plays. For example, some land bonus payments can be made in the same year as discovery.

[5]For a detailed discussion of the replacement cost concept, see P. Eglington and M. Uffelman, Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979.

[6]For a more detailed discussion of the supply curve concept, see ibid., pp. 21-23.

[7]Oilweek, February 4, 1985, pp. 31-32.

[8]P. Eglington and M. Uffelman, Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979.

Chapter 3

EXPENDITURES AND RESERVES DATA AND CRUDE OIL EQUIVALENT FINDING COSTS

3.1 Expenditures and Reserves Data

3.1.1 Expenditures

Expenditures data for Alberta were collected from the Canadian Petroleum Association (CPA) Statistical Handbook. The data were disaggregated into all exploration categories, and total exploration and total development expenditures were also used (see Table B.1).

The data were converted to 1983 constant dollars using indices from the CPA Capital Cost Escalation Study Update, 1984 (see Table B.2). Land expenditures were discounted using the exploration and development drilling index, as recommended by CPA. All other categories were discounted by their corresponding index.

In general, real exploration expenditures for Alberta increase to 1980 and decrease thereafter, with a slight increase in 1983 as well. This trend reflects the boom in the industry prior to the introduction of the National Energy Program (NEP) in 1980, the dampening effects of that program, and the beginning of the recent recovery in the industry.

Real development expenditures follow much the same trend, but continue to fall in 1983. Moreover, development expenditures appear to have been less sensitive to policy changes, generally increasing and decreasing more slowly than exploration expenditures.

3.1.2 Reserves

Unappreciated reserves data were collected from the CPA Statistical Handbook for each year's data. For example, the 1970 Handbook provided 1970 unappreciated reserves discovered, and so on.

Appreciation factors were determined for both oil and gas as described earlier. The appreciation factor was then applied to initial

unappreciated reserves to derive fully appreciated reserves for each year. These reserves were used to calculate finding costs.

Unlike expenditures, no clear pattern emerges for reserves (see Table B.3).

3.1.3 Data Qualifications

Two important qualifications to the data should be noted. First, geological and geophysical expenditures are likely overstated in that much of the seismic data collected throughout Canada is processed in Alberta. Thus, Alberta geological and geophysical expenditures include an unknown component of expenditures not directly attributable to Alberta oil and gas exploration.

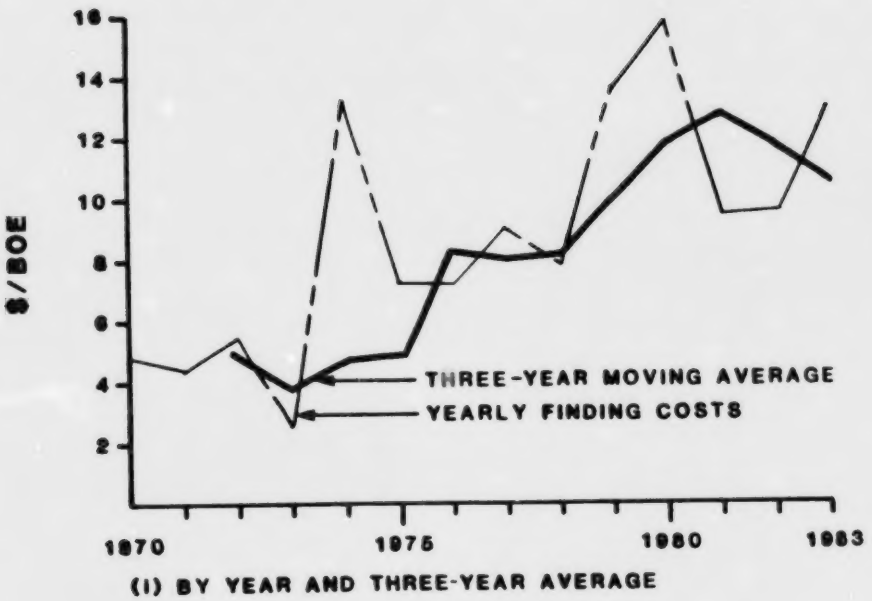
On the reserves side, initial discoveries for any given year are likely understated due to the confidentiality associated with new finds. These factors should be kept in mind when examining the finding cost results.

3.2 Basecase Finding Costs

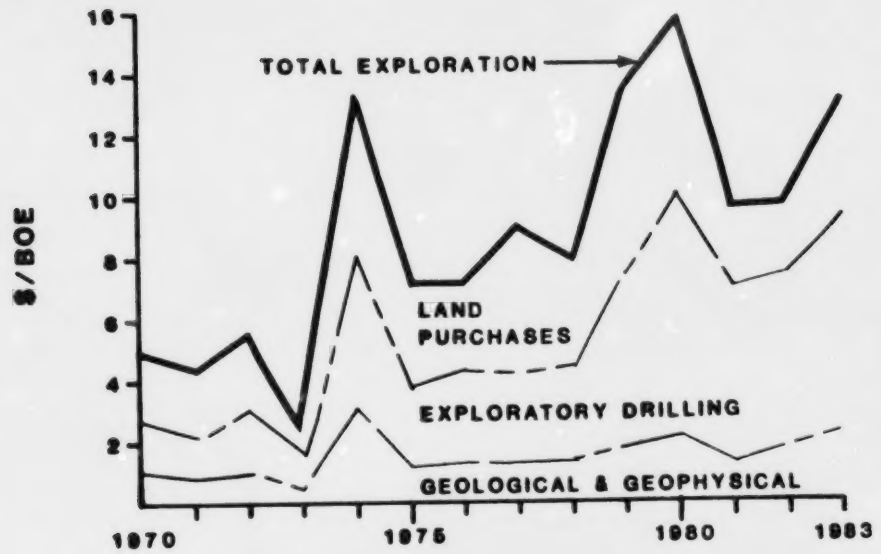
Finding costs, as previously discussed, are alternatively defined as including only exploration or exploration and development costs. The former definition is applied here, using constant 1983 dollar exploration expenditures. A further breakdown into the various components of exploration expenditures--geological and geophysical, exploration drilling, and land purchase and rentals--is also used to calculate the amount of finding costs attributable to each type of expenditure.

Alberta yearly finding costs show a relatively stable increasing trend that is magnified in the 3-year moving averages; rising to 1981 and decreasing thereafter (see Figure 3.1 and Table B.4). Neither the 5-year nor the 7-year moving average demonstrate this decrease after 1981.

The proportion of finding costs accounted for by geological and geophysical expenditures is about 15 percent throughout the period. Drilling and land purchase and rentals account for 35 to 40 percent and 45 to 50 percent, respectively, from 1970 to 1979. However, drilling accounts for the larger percentage from 1980 to 1983; increasing to between 50 and 60 percent, while land expenditures decrease to 25 to 35 percent.



(I) BY YEAR AND THREE-YEAR AVERAGE



(II) BY COST COMPONENT

SOURCE: Tables B.4 and B.5.

FIGURE 3.1: ALBERTA FINDING COSTS: 1970-1983

An alternative definition of finding costs includes development as well as exploration expenditures. Table B.5 presents these results for a simple case without any time-lagging of expenditures. On this basis, finding costs throughout the period approximately double.

3.3 Finding Cost Sensitivity Cases

The basecase finding cost results are determined using historical data under a given set of assumptions. However, while reserves data are fixed, the factor for converting natural gas to crude oil equivalent, for example, is an assumption and, therefore, can be altered.

To determine the relative impact of changes in the assumptions, five sensitivity cases are presented. The first two cases change the appreciation rates for crude oil and natural gas reserves; the third case adjusts land expenditures to account for development land expenditures; the fourth case alters the natural gas-to-crude conversion factor; and the final case uses a different source for reserves data to calculate finding costs.

3.3.1 Higher Reserves Appreciation

Significant disagreement exists among industry, government, and researchers regarding the rate of appreciation for crude oil and natural gas initial reserve discoveries. Much of the discrepancy occurs due to differences in the time periods examined as the discoveries of the 1950s and 1960s demonstrated far greater appreciation than more recent discoveries. Further differences occur due to the various data bases utilized.

As a case in point, the Alberta Energy Resources Conservation Board (ERCB) has also calculated appreciation rates using their own data from the 1950s to the present. These same data were used to calculate appreciation rates comparable to those developed from CPA data for the basecase. The same 1970 to 1983 period was used for natural gas from 1984 ERCB data. However, the most recent available crude oil data in this particular series is 1982. Therefore, the 1968 to 1981 period was used to maintain the 14-year time frame.

These calculations yielded crude oil and natural gas reserves appreciation rates of 4.12 and 7.50, respectively. On this basis,

Alberta finding costs are approximately half of basecase results (see Figure 3.2 and Table B.6).

3.3.2 No Reserves Appreciation

Finding costs based on unappreciated reserves basically triple from basecase finding costs due to the similar appreciation rates applied to both crude oil and natural gas reserves in the basecase (see Figure 3.2 and Table B.7). However, the general trend in finding costs remains consistent with basecase results.

3.3.3 Prorated Land and Rental Expenditures

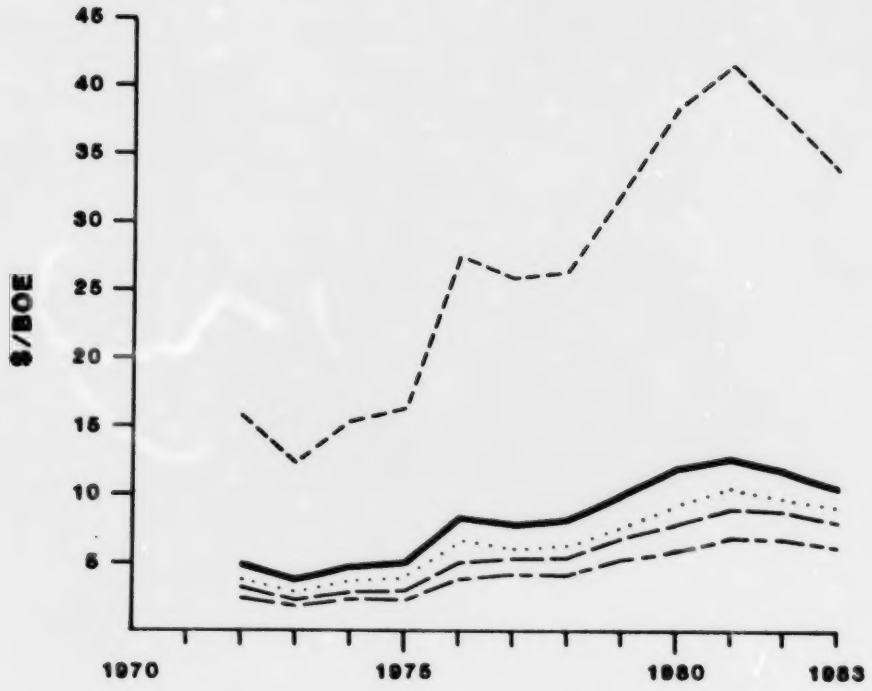
Exploration accounts for only a portion of total land and rentals expenditures with the remainder deemed to be used for development activity. Although no certain allocation can be made and the percentages would likely change from year to year, dividing land expenditures on a 50/50 basis between exploration and development will indicate the potential impact of this factor. Recalculating finding costs on this basis decreases finding costs between 15 and 30 percent from basecase results (see Figure 3.2 and Table B.8).

3.3.4 Crude Oil Equivalence Conversion

Natural gas can be converted to crude oil equivalent based on an energy content equivalence of 6 Mcf to 1 barrel as an alternative to price equivalence of 10.5 Mcf to 1 barrel. Given this change, Alberta finding costs decrease between 25 to 40 percent from the basecase, but follow the same general trend (see Figure 3.2 and Table B.9).

3.3.5 Alternative Reserves Data Source

As a final sensitivity, ERCB initial discoveries data were used to calculate first an appreciation rate and then finding costs for crude oil. This data series provides an appreciation rate of 2.41 for crude oil for the 1970 to 1983 period. (This figure differs from that of sensitivity case 1 because of the different data series and time frame used.) Oil exploration expenditures were separated out according to the methodology outlined in Chapters 2 and 5.



BASECASE
CASE 1 HIGHER RESERVES APPRECIATION
CASE 2 NO RESERVES APPRECIATION
CASE 3 50% OF LAND EXPENDITURES
CASE 4 ENERGY EQUIVALENCE CONVERSION

SOURCE: Tables B.4 and B.6 - B.9.

[a] THREE-YEAR MOVING AVERAGES.

FIGURE 3.2: ALBERTA FINDING COST SENSITIVITY CASES: 1970-1983[a]

On the basis of these data, 3-year moving average crude oil finding costs amount to only 30 to 50 percent of those calculated on the basis of CPA data (see Table B.10). Significantly larger initial discoveries in the ERCB data series for almost every year account for this difference.

3.3.6 Summary

Of the sensitivities presented, the largest impacts occur with changes in the appreciation rates and the reserves data. This suggests that reserves appreciation and reserves data are critical elements to which close attention should be paid in any analysis of finding costs.

The assumption of no appreciation is unlikely in reality, but does indicate the sensitivity of finding costs to the level of reserves appreciation. The other changes--prorated land expenditures and energy equivalence conversion of natural gas to crude oil--generally do not have a significant impact on finding costs.

Chapter 4

SOME EXTENSIONS TO THE BASECASE ANALYSIS

4.1 Introduction

The basecase finding cost results provide aggregate figures which are, for that reason, limited in their application. Several avenues are available to increase the sophistication of these results. This chapter addresses three such alternatives: separate finding costs for crude oil and natural gas; finding cost estimates using time-lagged expenditures; and replacement as opposed to finding costs.

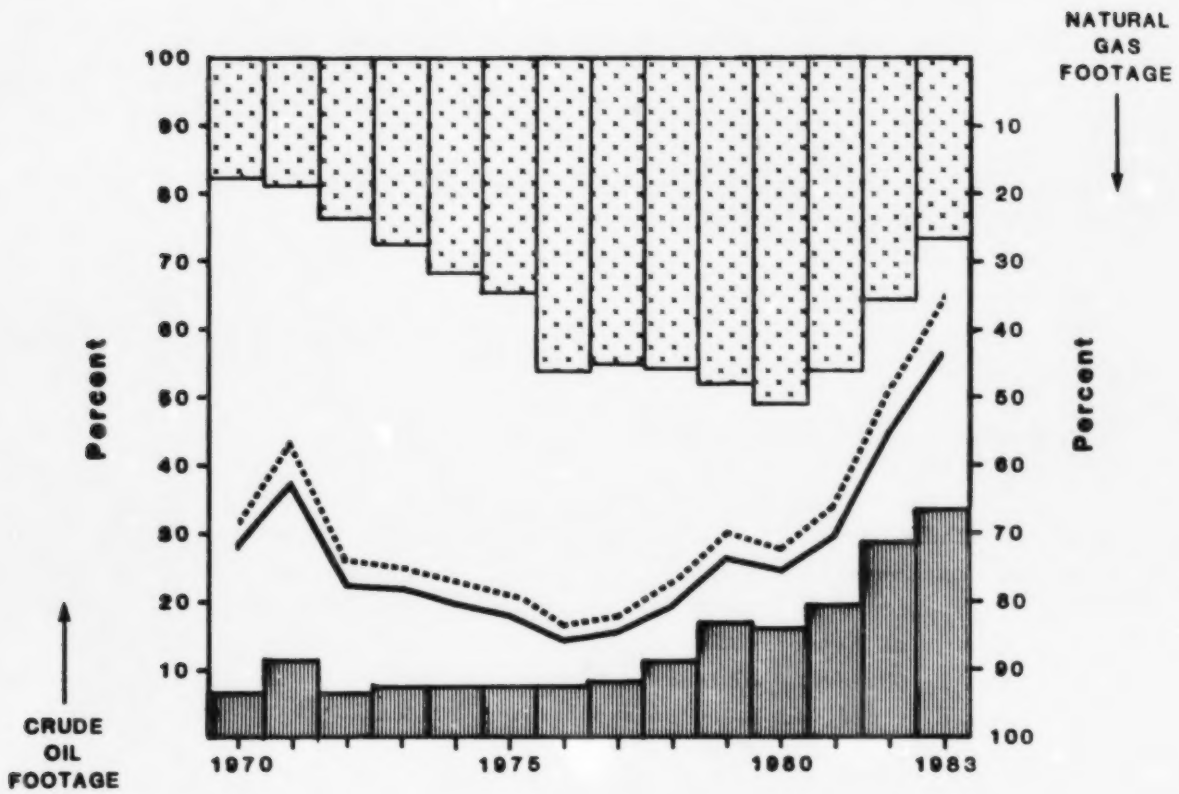
4.2 Separate Crude Oil and Natural Gas Finding Costs

Calculating crude oil and natural gas finding costs separately requires some measure of the intentions of petroleum companies in their exploratory endeavors: i.e., whether they are searching for oil or gas. The difficulties associated with determining intent have been discussed in Chapter 2. However, while intent cannot be determined precisely, some estimate can be derived based on exploratory success.

One possible proxy for oil intent is the ratio of all successful exploratory wells to total exploratory wells drilled. However, this method results in a declining measure of oil intent since 1980 which does not parallel actual activity.

A second method uses successful exploratory oil wells divided by total successful wells drilled to estimate oil intent. A further possibility is to employ the same method using footage drilled as opposed to number of wells drilled. This latter approach provides a curve commensurate with the trend in industry activity (see Figure 4.1 and Table C.1) and, therefore, is used in determining the relative proportion of total exploration expenditures to be allocated to oil (i.e., the intent ratio). The remainder is assigned to gas exploration.

Yearly finding costs calculated on this basis exhibit the wide fluctuations seen in the crude equivalent finding costs. However, the general trends in the 3-year moving averages differ from the oil equivalent basecase, as well as between crude oil and natural gas finding



SOURCE: Table C.1.

FIGURE 4.1: INTENT ESTIMATION FOR ALBERTA EXPLORATION ACTIVITY: 1970-1983

costs. The basecase trend in Alberta's 3-year moving average finding costs is an increase to 1981 with a decrease thereafter. Three-year moving average crude oil finding costs, on the other hand, demonstrate a fluctuating trend, peaking in 1976 and 1980, and increasing again as of 1983 (see Figure 4.2 and Table C.2). Natural gas 3-year moving average finding costs basically rise throughout the period, but fall in 1983 (see Figure 4.2 and Table C.3).

Figure 4.2 also presents separate oil and gas finding costs calculated on the basis of estimated intent increased by a factor of 15 percent in favor of oil exploration expenditures. This is done to account for the greater inherent risk associated with exploration for crude oil relative to natural gas. Crude oil finding costs calculated on this basis increase about 15 percent throughout the period. However, natural gas finding costs decrease 10 percent from 1972 to 1974 and in 1983, but fall only 2 to 6 percent in the interim (see Figure 4.2 and Tables C.4 and C.5). Nevertheless, the same general trend is followed in both cases.

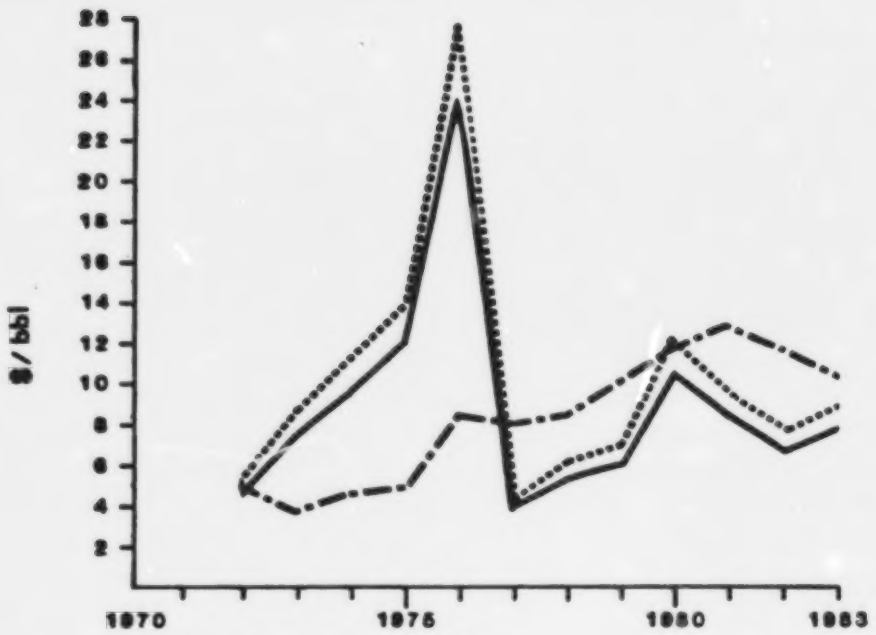
4.3 Finding Costs with Time-Lagged Expenditures

A second extension to the basecase analysis is to lag expenditures so as to more accurately reflect the actual expenditure process in oil and gas exploration. As previously discussed, land expenditures and geological and geophysical expenditures are lagged two years and one year, respectively.

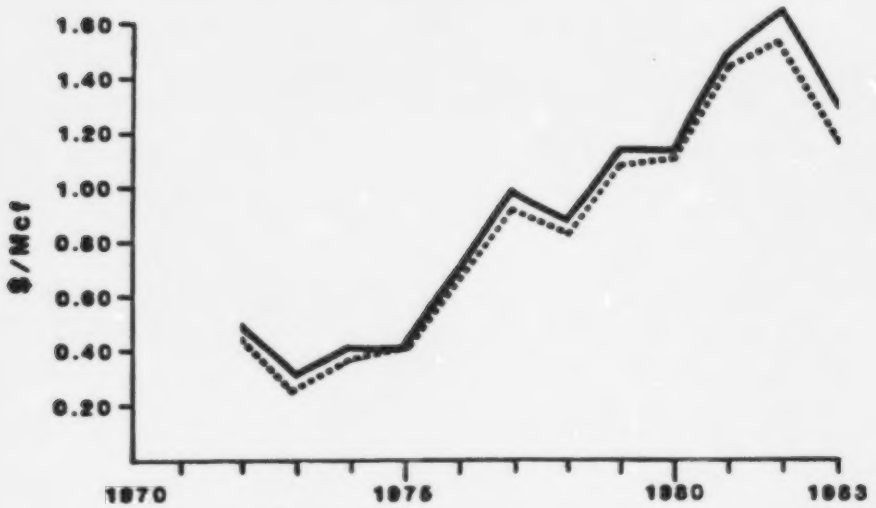
As with the basecase results, yearly finding costs for Alberta based on lagged expenditures fluctuate considerably. However, the 3-year moving average figures indicate a definite upward trend (see Figure 4.3 and Table C.6). Lagging expenditures seems to accentuate the lows and peaks of the basecase while following the same basic trend. The relatively high interest rates after 1980 (see Table C.7) account for the increased differential between the basecase and the lagged expenditures case from 1981 on.

4.4 Reserves Replacement Costs

A further step in the analysis is to examine reserves replacement costs. The cost of replacing existing established reserves of crude oil and natural gas can be determined by examining finding and development costs. Production costs could also be included to calculate replacement



(I) CRUDE OIL FINDING COSTS



(II) NATURAL GAS FINDING COSTS

—— ESTIMATED INTENT FINDING COSTS

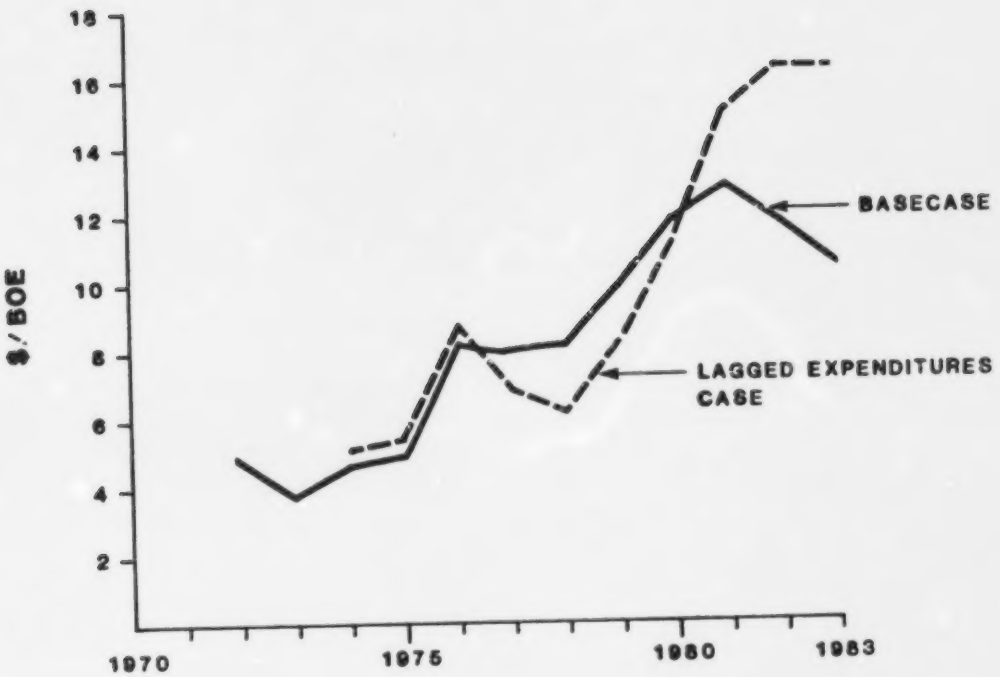
------ ESTIMATED INTENT +15% FINDING COSTS

-•-•- CRUDE OIL EQUIVALENT BASECASE FINDING COSTS ($/BOE)

SOURCE: Tables C.2 - C.5.

[a] THREE-YEAR MOVING AVERAGES.

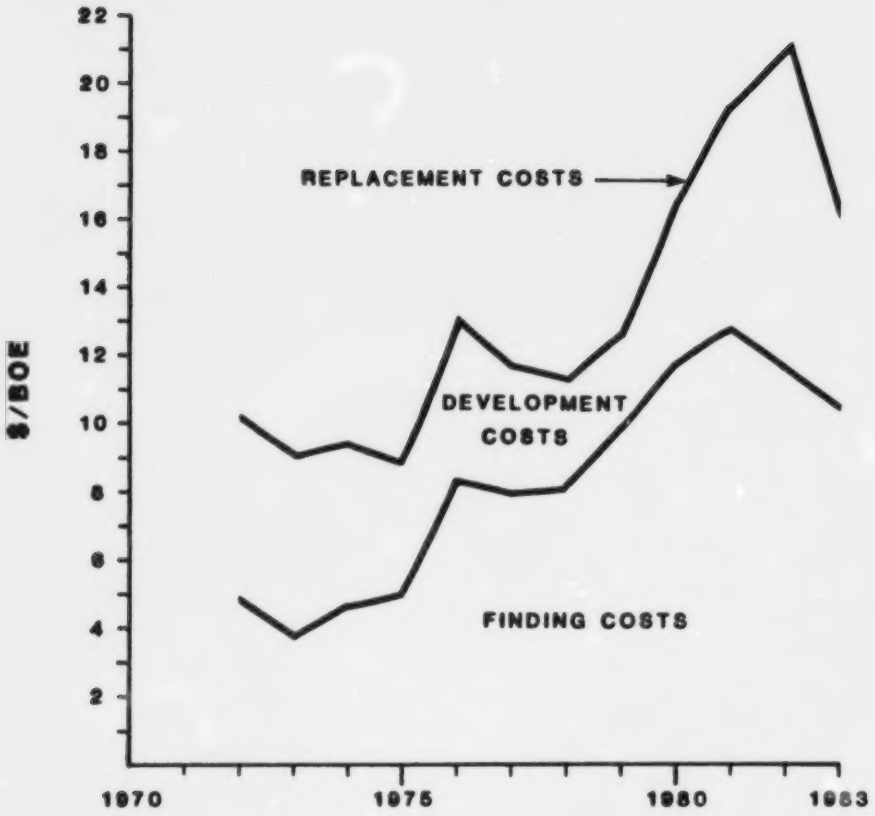
FIGURE 4.2: ALBERTA CRUDE OIL AND NATURAL GAS FINDING COSTS: 1970-1983 [a]



SOURCE: Table C.6.

[a] THREE-YEAR MOVING AVERAGES. LAND EXPENDITURES AND GEOLOGICAL AND GEOPHYSICAL EXPENDITURES LAGGED 2 YEARS AND 1 YEAR, RESPECTIVELY.

FIGURE 4.3: ALBERTA LAGGED EXPENDITURES FINDING COSTS: 1970-1983 [a]



SOURCE: Table C.8.

[a] THREE-YEAR MOVING AVERAGES.

FIGURE 4.4: ALBERTA OIL AND GAS RESERVES REPLACEMENT COSTS: 1970-1983 [a]

costs per barrel of crude equivalent produced as opposed to replacing reserves in the ground. However, the former methodology is employed in this study.

Yearly per barrel development costs of crude oil equivalent were determined by dividing total development costs by total reserves revisions and extensions for that year (see Table C.8). These results were added to the basecase finding cost results to determine replacement costs for each year. Similarly, 3-year moving average development and finding costs were added to obtain 3-year moving average replacement costs.

Figure 4.4 presents 3-year moving average replacement costs for Alberta reserves from 1972 to 1983. The general trend parallels that of the basecase finding costs with a slight lag; increasing to 1982 and decreasing thereafter. Three-year moving average replacement costs peak in 1982 at $21 per barrel of oil equivalent, and fall in 1983 to $16 per BOE, slightly lower than the 1980 level.

Development costs follow much the same trend as replacement and finding costs. It is interesting to note that the percentage of replacement costs attributable to finding costs also follows this general trend; increasing from 1972 to 1979, decreasing in 1982 and then increasing in 1983. The 1983 level of 64 percent is considerably greater than the 48 percent level of 1972.

4.5 Further Extensions to the Analysis

The methodologies employed both for separating oil and gas finding costs and for calculating replacement costs could be further refined with more disaggregated data and additional analysis. These results could also be extended to other geographical areas. The basecase finding costs and other results could be derived on a less aggregated basis by examining particular geological or geographical areas of Alberta. However, considerably more detail in the data base would be required.

Although it is not clear that further refinements in methodology would sufficiently improve the results to warrant the additional time and effort required, extension of the results to other geographic regions or smaller regions would provide interesting and more specific results.

Chapter 5

SUMMARY AND CONCLUSIONS

5.1 Finding Cost Results

The prime objective of this research report is to provide estimates of petroleum finding costs for the Province of Alberta during the period of 1970 to 1983.

The cost of finding a unit of crude oil or equivalent is defined as the ratio of exploratory expenditures of a given year to reserves discovered in the same year, fully appreciated to the year of discovery. The finding cost results are presented in a basecase and five sensitivity cases to accommodate changes in some of the critical variables.

Separate crude oil and natural gas finding costs are calculated by estimating the intent of exploration on the basis of successful exploratory drilling footage. Land expenditures and geological and geophysical expenditures are lagged to determine the effect of the timing of expenditures on finding costs. Replacement costs, defined as the cost of replacing or booking reserves in the ground, are also estimated. Table 5.1 summarizes some of the results.

The basecase yearly finding costs for crude oil equivalent are relatively stable with fluctuations primarily due to the corresponding swings in the amount of reserves discovered in each year. The trend shown by the 3-year moving average finding costs, however, parallels more closely the trend in exploratory expenditures; rising to 1981 and declining thereafter. The 5-year and 7-year moving average finding costs show a definite upward trend. To the extent that the Province of Alberta accounts for most of Canadian petroleum production and exploration, the main conclusion of this study is that finding costs are generally increasing.

Five sensitivity cases are investigated: (i) higher reserves appreciation rates; (ii) no reserves appreciation; (iii) prorated land and rental expenditures; (iv) alternative crude oil equivalence

TABLE 5.1

SUMMARY OF ALBERTA FINDING COST RESULTS
1970-1983
(1983$; 3-year moving averages)

	Basecase ($/BOE)	Crude Oil ($/bbl)	Natural Gas ($/Mcf)	Lagged Expenditures ($/BOE)	Replacement Costs ($/BOE)
1970	NA	NA	NA	NA	NA
1971	NA	NA	NA	NA	NA
1972	4.90	4.60	0.50	NA	10.20
1973	3.70	7.50	0.30	NA	9.00
1974	4.70	9.50	0.40	5.20	9.40
1975	5.00	12.00	0.40	5.60	8.80
1976	8.40	24.30	0.70	8.80	13.20
1977	8.00	3.70	1.00	6.90	11.70
1978	8.10	5.20	0.90	6.30	11.30
1979	9.90	6.00	1.10	8.40	12.60
1980	11.80	10.70	1.20	11.30	16.50
1981	12.80	8.30	1.50	15.00	19.40
1982	11.70	6.90	1.60	15.90	21.20
1983	10.50	7.80	1.30	15.90	16.40

SOURCE: Tables B.4, C.2, C.3, C.6, and C.8.

conversion; and (v) alternative source of reserves data. In these sensitivity analyses, the largest impact on the basecase results occurs with changes in reserves data and appreciation rates. This suggests that reserves data and reserves appreciation are critical elements in analyzing finding costs. Close attention should, therefore, be paid to assumptions regarding these variables in interpreting any finding cost estimates. The other sensitivity cases generally do not have a significant impact on the basecase results.

When oil and gas finding costs are separated, similar trends are obtained, although the cost of finding crude oil is somewhat reduced relative to that of the crude oil equivalent basecase. Nevertheless, finding costs still exhibit a rising trend.

Lagging land expenditures and geological and geophysical expenditures likely more closely reflects the actual expenditure process involved in oil and gas exploration. However, the net result is simply to accentuate the low and high points while maintaining the same general trend as the basecase; increasing to 1981 or 1982 with a slight drop thereafter. Given some of the limitations of the results as discussed earlier, it is advisable to pay closer attention to the overall trend in provincial finding costs rather than to the absolute numbers in any given year.

5.2 Policy Implications

In terms of the implications for government policy, the impact is fairly clear in spite of the limitations inherent in the data used and the scope of this study. As finding cost is an important part of the full-cycle cost of producing hydrocarbons, unless development and production costs are declining, the full-cycle cost is rising over time. And, as the selling price is presently under strong downward pressure, lower tax or royalty payments may be required in order to maintain the future economic attractiveness of petroleum exploration.

This conclusion assumes that it is preferable to continue domestic exploration and production of petroleum, rather than increasing the reliance on imports, which may prove cheaper during certain time periods. As crude oil self-sufficiency (total or to the highest degree possible) is still presumed to be a government objective for Canada, the economic viability of crude oil exploration and production should also be a policy objective. However, to assess the economics of petroleum production as a whole, more detailed analysis of the full-cycle economics or profitability would have to be undertaken.

APPENDIX A

CRUDE OIL AND NATURAL GAS RESERVES APPRECIATION

TABLE A.1

ALBERTA CRUDE OIL RESERVES APPRECIATION[a]
1970-1983
($10^6 m^3$)

Year of Discovery	0	1	2	3	4	5	6	7	8	9	10	11	12	13
1970	6.6	7.6	7.8	6.5	6.5	6.5	6.4	6.3	6.9	7.6	7.5	7.5	8.0	8.1
1971	3.1	4.3	5.0	6.7	6.6	6.5	6.2	6.4	5.9	6.9	8.6	9.3	8.2	
1972	1.3	1.8	2.8	2.5	2.5	5.0	5.5	5.1	5.1	5.3	5.5	5.6		
1973	1.8	1.8	5.1	7.8	6.3	5.8	6.3	5.8	5.9	5.8	6.3			
1974	0.8	1.2	1.7	2.3	2.6	3.0	3.3	3.8	4.0	3.8				
1975	0.3	1.1	1.0	1.2	1.3	1.2	1.2	1.6	1.5					
1976	0.2	0.8	2.8	16.9	17.1	5.3	6.2	6.5						
1977	10.0	28.0	28.8	31.6	7.7	9.3	11.4							
1978	0.8	7.1	8.6	28.4	29.6	31.9								
1979	4.9	8.1	15.4	15.0	18.4									
1980	5.9	2.5	3.5	3.8										
1981	5.5	8.4	10.0											
1982	7.8	10.1												
1983	4.2													
Sum of Column	53.2	82.8	92.5	122.7	98.6	74.5	46.5	35.5	29.3	29.4	27.9	22.4	16.2	8.1
Sum of Previous Column[b]	NA	49.0	72.7	82.5	118.9	80.2	42.6	35.1	29.0	27.8	25.6	21.6	16.8	8.0
Appreciation Factor[c]	NA	1.7	1.3	1.5	0.8	0.9	1.1	1.0	1.0	1.1	1.1	1.0	1.0	1.0
Appreciation Rate[d]	NA	1.7	2.1	3.2	2.7	2.5	2.7	2.7	2.7	2.9	3.2	3.3	3.2	3.2

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, 1971 to 1984 editions (Calgary: Canadian Petroleum Association, 1970-1984), Reserves Section.

[a]Ultimate probable crude oil reserves for 1970. Probable ultimate recoverable crude oil reserves for 1971 to 1977. Initial established in-place crude oil reserves for 1978. Initial established crude oil reserves for 1979 to 1983.

[b]Sum of previous column less last entry so as to include the same years as in the column sum.

[c]Sum of column divided by the sum of previous column (less last entry: see note b).

[d]Appreciation factors (to two decimal places) compounded (multiplied) to yield total appreciation rate. The appreciation rate after 13 years is 3.20.

TABLE A.2

ALBERTA NATURAL GAS RESERVES APPRECIATION[a]
1970-1983
($10^9 m^3$)

Year of Discovery	0	1	2	3	4	5	6	7	8	9	10	11	12	13
1970	9.4	17.0	16.6	20.4	20.7	26.8	23.2	26.2	27.5	19.6	28.3	27.2	29.6	22.7
1971	18.5	33.8	31.6	28.8	26.8	27.9	30.6	36.0	41.0	44.9	47.2	43.0	41.1	
1972	16.1	28.5	34.1	33.3	43.2	41.2	39.1	42.2	58.3	55.0	52.0	59.3		
1973	38.2	8.1	21.9	24.9	25.0	32.5	28.6	31.6	33.3	36.3	36.7			
1974	6.8	18.7	36.2	43.2	47.9	86.7	93.0	96.6	101.2	101.1				
1975	12.5	17.1	17.4	35.6	47.0	51.3	52.2	56.9	52.9					
1976	17.5	31.5	53.4	72.1	63.8	64.2	65.3	67.3						
1977	7.5	33.0	45.4	44.0	56.3	57.2	60.5							
1978	28.4	34.8	53.0	52.2	53.7	48.0								
1979	15.2	44.3	53.3	78.8	84.4									
1980	10.9	20.2	22.8	28.8										
1981	15.5	19.4	25.3											
1982	3.6	42.7												
1983	5.5													
Sum of Column	205.6	349.1	411.0	462.1	468.8	435.8	392.5	356.8	314.2	256.9	164.2	129.5	70.7	22.7
Sum of Previous Column[b]	NA	200.1	306.4	385.7	433.3	384.4	387.8	332.0	289.5	261.3	155.8	127.5	70.2	29.6
Appreciation Factor[c]	NA	1.7	1.3	1.2	1.1	1.1	1.0	1.1	1.1	1.0	1.1	1.0	1.0	0.8
Appreciation Rate[d]	NA	1.7	2.3	2.8	3.0	3.4	3.4	3.7	4.0	3.9	4.1	4.2	4.3	3.3

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, 1971 to 1984 editions (Calgary: Canadian Petroleum Association, 1970-1984), Reserves Section.

[a]Ultimate probable marketable natural gas reserves for 1970. Probable ultimate recoverable marketable natural gas reserves for 1971 to 1977. Initial established in-place marketable natural gas reserves for 1978. Initial established marketable natural gas reserves for 1979 to 1983.

[b]Sum of previous column less last entry so as to include the same years as in the column sum.

[c]Sum of column divided by the sum of previous column (less last entry: see note b).

[d]Appreciation factors (to two decimal places) compounded (multiplied) to yield total appreciation rate. The appreciation rate after 13 years is 3.28.

APPENDIX B

EXPENDITURES AND RESERVES DATA AND CRUDE OIL EQUIVALENT FINDING COSTS

TABLE B.1

ALBERTA
NET CASH EXPENDITURES
1970 - 1983
(CURRENT MILLIONS OF DOLLARS)

	EXPLORATION					
YEAR	GEOLOGICAL AND GEOPHYSICAL	DRILLING	LAND PURCHASE AND RENTALS	TOTAL EXPLORATION	DEVELOPMENT	EXPLORATION AND DEVELOPMENT
1970	80	84	117	281	328	608
1971	66	81	126	272	376	648
1972	71	102	124	298	333	631
1973	71	131	144	346	351	697
1974	112	147	157	416	455	872
1975	99	149	208	456	562	1018
1976	146	257	256	658	846	1503
1977	223	395	680	1298	861	2159
1978	350	645	741	1735	1129	2865
1979	350	1028	1145	2522	1538	4060
1980	452	1622	1177	3250	2341	5591
1981	352	1544	721	2617	2418	5036
1982	325	1076	466	1867	2408	4275
1983	325	1017	565	1908	1801	3709

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, as updated to 1984 (Calgary: Canadian Petroleum Association, 1984), Section II, Tables 3,4.

TABLE B.2

CPA COST ESCALATION INDICES
BY EXPENDITURE TYPE
1970 - 1983
(1983 = 100)

YEAR	GEOLOGICAL AND GEOPHYSICAL COSTS	EXPLORATION AND DEVELOPMENT DRILLING	FIELD EQUIPMENT	GAS PLANT CONSTRUCTION COSTS	TOTAL CONSTRUCTION COSTS	WELL OPERATING COSTS	GAS PLANT OPERATING COSTS	TOTAL OPERATING COSTS
1970	30.5	21.0	22.5	15.8	20.7	21.3	19.1	20.7
1971	32.6	21.6	24.0	17.9	22.4	24.0	22.7	23.9
1972	34.5	24.2	26.7	19.8	24.7	27.0	24.2	26.3
1973	36.9	27.7	31.9	22.0	28.2	33.4	24.6	30.5
1974	40.9	33.0	40.4	25.2	33.8	35.1	29.0	33.2
1975	50.6	38.9	47.9	29.7	40.0	44.0	36.8	41.9
1976	56.7	44.3	53.9	41.3	47.1	52.1	45.6	50.4
1977	62.5	48.7	60.4	53.0	52.1	62.3	54.2	60.2
1978	72.6	56.9	65.2	64.6	59.1	71.1	64.5	69.5
1979	78.7	68.5	73.0	72.3	68.7	82.1	68.9	78.6
1980	86.0	85.1	80.2	79.6	81.3	88.1	83.2	87.1
1981	92.1	94.1	90.3	89.9	91.1	92.3	93.9	92.9
1982	98.2	98.1	98.0	98.1	98.1	98.1	98.1	98.1
1983	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

SOURCES: (1) Canadian Petroleum Association, "Capital Cost Escalation Study Update". Calgary: CPA, 1984. Mimeod.; and (2) Personal communication with the Canadian Petroleum Association.

TABLE B.3

ALBERTA CRUDE OIL, PENTANES PLUS,
NATURAL GAS LIQUIDS, AND MARKETABLE NATURAL GAS
INITIAL ESTABLISHED RESERVES
1970 - 1983
(THOUSANDS OF BARRELS)

YEAR	TOTAL CRUDE	PENTANES PLUS AND NGL	MARKETABLE NATURAL GAS	TOTAL CRUDE + NG EQUIV.
1970	41281.0	4368.0	31627.0	77276.0
1971	19271.0	55.0	62094.8	81420.8
1972	8372.0	1194.0	54179.4	63745.4
1973	11223.0	153.0	128639.3	140015.3
1974	4779.0	50.0	22883.4	27712.4
1975	1981.0	3640.0	42169.0	47790.0
1976	1380.0	125.0	58820.2	60325.2
1977	62860.0	68.0	25059.7	87987.7
1978	4667.0	11793.0	95669.2	112129.2
1979	30952.0		51166.0	82118.0
1980	36821.0	1453.0	36613.0	74887.0
1981	34739.0	2258.0	52010.2	89007.2
1982	48828.0		11959.9	60787.9
1983	26600.0	113.0	18572.2	45285.2

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, 1967 to 1983 editions. Calgary: Canadian Petroleum Association, 1968 - 1984. Reserves Section.

TABLE B.4

ALBERTA
FINDING COSTS
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	4.87			
1971	4.36			
1972	5.48	4.86		
1973	2.59	3.74		
1974	13.21	4.65	4.63	
1975	7.11	4.96	4.91	
1976	7.14	8.36	5.44	5.18
1977	9.04	7.98	6.30	5.88
1978	7.94	8.12	8.40	6.54
1979	13.55	9.91	9.14	7.69
1980	15.72	11.80	10.54	10.36
1981	9.65	12.79	10.83	10.10
1982	9.73	11.70	11.04	10.32
1983	13.03	10.46	12.30	10.89

SOURCE: Tables B.1 - B.3.

TABLE B.5

ALBERTA
FINDING COSTS
BY EXPENDITURE TYPE
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

	EXPLORATION					
YEAR	GEOLOGICAL AND GEOPHYSICAL	DRILLING	LAND PURCHASE AND RENTALS	TOTAL EXPLORATION	DEVELOPMENT	EXPLORATION AND DEVELOPMENT
1970	1.05	1.60	2.22	4.87	7.15	12.02
1971	0.76	1.41	2.20	4.36	7.16	11.52
1972	0.99	2.02	2.47	5.48	6.82	12.30
1973	0.42	1.03	1.14	2.59	2.72	5.31
1974	3.04	4.90	5.27	13.21	15.46	28.67
1975	1.25	2.45	3.41	7.11	9.22	16.33
1976	1.30	2.93	2.92	7.14	8.97	16.12
1977	1.26	2.86	4.92	9.04	5.67	14.72
1978	1.31	3.08	3.54	7.94	5.03	12.97
1979	1.67	5.62	6.26	13.55	8.17	21.72
1980	2.17	7.85	5.70	15.72	11.71	27.42
1981	1.32	5.67	2.65	9.65	9.10	18.74
1982	1.69	5.61	2.43	9.73	12.56	22.30
1983	2.22	6.95	3.86	13.03	12.30	25.33

SOURCE: Tables B.1 - B.3.

TABLE B.6

SENSITIVITY ONE: HIGHER RESERVES APPRECIATION[a]

ALBERTA
FINDING COSTS
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	2.77			
1971	2.12			
1972	2.54	2.45		
1973	1.17	1.74		
1974	6.24	2.13	2.24	
1975	3.17	2.25	2.27	
1976	3.15	3.75	2.47	2.45
1977	5.73	4.08	3.05	2.84
1978	3.53	4.01	4.06	3.09
1979	7.07	5.10	4.50	3.70
1980	8.72	5.83	5.37	5.18
1981	5.07	6.82	5.67	5.10
1982	6.54	6.65	5.75	5.42
1983	7.64	6.85	6.88	5.89

SOURCE: Table B.1-B.3

[a]Crude appreciation = 4.12
Natural Gas appreciation = 7.50

TABLE B.7

SENSITIVITY TWO: NO RESERVES APPRECIATION

ALBERTA
FINDING COSTS
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	15.76			
1971	14.22			
1972	17.92	15.81		
1973	8.48	12.23		
1974	43.14	15.23	15.12	
1975	23.30	16.22	16.07	
1976	23.41	27.40	17.82	16.91
1977	29.14	25.95	20.54	19.20
1978	26.01	26.47	27.39	21.37
1979	44.03	32.23	29.77	25.09
1980	50.93	38.44	34.31	33.74
1981	31.34	41.54	35.19	32.88
1982	31.30	37.86	35.90	33.52
1983	42.12	33.83	39.85	35.33

SOURCE: Tables B.1-B.3

TABLE B.8

SENSITIVITY THREE: 50 PERCENT OF LAND EXPENDITURES

ALBERTA
FINDING COSTS
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	3.76			
1971	3.26			
1972	4.25	3.72		
1973	2.02	2.87		
1974	10.57	3.66	3.59	
1975	5.40	3.87	3.80	
1976	5.68	6.58	4.26	4.02
1977	6.58	6.01	4.82	4.50
1978	6.17	6.19	6.44	5.03
1979	10.42	7.53	6.98	5.91
1980	12.87	9.31	8.22	8.07
1981	8.32	10.40	8.58	7.99
1982	8.52	9.89	8.99	8.26
1983	11.10	9.03	10.17	8.78

SOURCE: Tables B.1-B.3

TABLE B.9

SENSITIVITY FOUR: ENERGY EQUIVALENCE CONVERSION[a]

ALBERTA
FINDING COSTS
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	3.71			
1971	2.77			
1972	3.34	3.23		
1973	1.53	2.27		
1974	8.14	2.79	2.94	
1975	4.28	2.96	2.98	
1976	4.12	4.96	3.24	3.23
1977	7.43	5.37	4.00	3.72
1978	4.84	5.34	5.42	4.10
1979	9.21	6.78	5.98	4.89
1980	11.46	7.79	7.10	6.86
1981	6.69	8.94	7.51	6.77
1982	8.46	8.73	7.63	7.15
1983	9.93	7.91	9.00	7.78

SOURCE: Tables B.1-B.3

[a]Natural gas converted to crude equivalence based on energy equivalence of 6 Mcf = 1 barrel.

TABLE B.10

ALBERTA CRUDE OIL FINDING COSTS
1970-1983
(ERCB Data)

	Exploration Expenditures (millions 1983$)	Estimated Oil Intent[a] (%)	Estimated Oil Expl. Expd. (millions 1983$)	ERCB Initial Discoveries (million bbl)	ERCB Appreciated Initial Discoveries[b] (million bbl)	Finding Costs		3-Year Moving Average	
						ERCB Data (1983$/ bbl)	CPA Data[c] (1983$/ bbl)	ERCB Data (1983$/ bbl)	CPA Data[c] (1983$/ bbl)
1970	1,218	27.5	335.0	52.8	127.2	2.63	2.53	NA	NA
1971	1,158	37.4	433.1	88.1	212.3	2.04	7.02	NA	NA
1972	1,142	22.1	252.4	67.9	163.6	1.54	9.38	2.03	4.62
1973	1,187	21.4	254.0	32.1	77.4	3.28	7.07	2.07	7.54
1974	1,195	19.8	236.6	27.0	65.1	3.63	15.48	2.43	9.51
1975	1,113	17.9	199.2	10.1	24.3	8.20	31.44	4.14	11.99
1976	1,412	14.1	199.1	15.7	37.8	5.27	44.78	4.99	24.33
1977	2,564	15.4	394.9	30.2	72.8	5.42	1.96	5.88	3.74
1978	2,917	19.7	574.6	156.6	377.4	1.52	37.50	2.39	5.23
1979	3,615	26.2	947.1	120.8	291.1	3.25	9.56	2.59	6.04
1980	3,814	24.2	923.0	56.6	136.4	6.77	8.16	3.04	10.65
1981	2,789	29.7	828.3	94.3	227.3	3.64	7.45	4.12	8.34
1982	1,903	44.7	850.6	105.7	254.7	3.34	5.44	4.21	6.85
1983	1,908	55.8	1,064.7	134.6	324.4	3.28	12.51	3.40	7.78

SOURCE: Alberta Energy Resources Conservation Board, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, ERCB 72-18 to 84-18 (Calgary: Alberta Energy Resources Conservation Board, 1972 to 1984), Table on Anticipated Crude Oil Appreciation for 72-18 to 76-18, Table A.4 for 77-18 to 84-18.

[a]From Table C.1
[b]Appreciation rate = 2.41.
[c]From Table C.2.

APPENDIX C

RESULTS OF EXTENDED ANALYSES

TABLE C.1

INTENT ESTIMATION FOR ALBERTA EXPLORATION ACTIVITY
1970-1983
(percent)

Year	Successful Oil/ Total Exploratory	Successful Gas/ Total Exploratory	Estimated Oil Intent[a]	Estimated Oil Intent + 15%[b]
1970	6.7	17.8	27.5	31.6
1971	11.3	18.9	37.4	43.0
1972	6.6	23.3	22.1	25.4
1973	7.4	27.2	21.4	24.6
1974	7.4	30.2	19.8	22.8
1975	7.5	34.5	17.9	20.6
1976	7.5	46.0	14.1	16.2
1977	8.2	45.0	15.4	17.7
1978	11.1	45.6	19.7	22.7
1979	16.9	47.7	26.2	30.1
1980	16.2	50.8	24.2	27.8
1981	19.5	46.0	29.7	34.2
1982	28.8	35.6	44.7	51.4
1983	33.6	26.6	55.8	64.2

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, as updated to 1984 (Calgary: Canadian Petroleum Association, 1984), Section 1, Tables 5-5A.

[a]Successful oil/total successful.
[b]Estimated intent x 1.15.

TABLE C.2

ALBERTA CRUDE OIL FINDING COSTS:
ESTIMATED INTENT ONLY
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	2.53			
1971	7.82			
1972	9.38	4.62		
1973	7.07	7.54		
1974	15.48	9.51	5.56	
1975	31.44	11.99	9.41	
1976	44.78	24.33	12.83	6.75
1977	1.96	3.74	4.87	5.59
1978	37.50	5.23	6.56	6.87
1979	9.56	6.84	7.05	7.40
1980	8.16	18.65	7.00	7.62
1981	7.45	8.34	6.78	7.37
1982	5.44	6.85	8.31	6.73
1983	12.51	7.78	8.17	7.14

SOURCE: Tables B.1-B.3 and C.1.

TABLE C.3

ALBERTA NATURAL GAS FINDING COSTS:
ESTIMATED INTENT ONLY
(EXPLORATION EXPENDITURES ONLY)
1978 - 1983
(1983 CONSTANT DOLLARS PER THOUSAND CUBIC FEET)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	0.71			
1971	0.34			
1972	0.53	0.49		
1973	0.21	0.31		
1974	1.21	0.41	0.43	
1975	0.58	0.41	0.42	
1976	0.60	0.70	0.47	0.47
1977	2.51	0.96	0.64	0.58
1978	0.64	0.87	0.85	0.62
1979	1.51	1.14	0.94	0.74
1980	2.18	1.16	1.16	1.09
1981	1.05	1.51	1.26	1.08
1982	2.55	1.63	1.20	1.19
1983	1.31	1.32	1.56	1.32

SOURCE: Tables B.1-B.3 and C.1.

TABLE C.4

ALBERTA CRUDE OIL FINDING COSTS:
ESTIMATED OIL INTENT + 15%
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	2.91			
1971	8.07			
1972	10.83	5.32		
1973	8.13	8.68		
1974	17.82	10.96	6.39	
1975	36.18	13.80	10.83	
1976	51.81	28.05	14.79	7.77
1977	2.26	4.30	5.61	6.44
1978	44.33	6.10	7.63	7.97
1979	10.99	6.99	8.17	8.56
1980	9.00	12.12	7.99	8.70
1981	8.38	9.46	7.75	8.43
1982	6.26	7.77	9.50	7.70
1983	14.39	8.95	9.32	8.17

SOURCE: Tables B.1-B.3 and C.1.

TABLE C.5

ALBERTA NATURAL GAS FINDING COSTS:
ESTIMATED OIL INTENT + 15%
(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER THOUSAND CUBIC FEET)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970	0.67			
1971	0.3[illegible]			
1972	0.45	0.44		
1973	0.20	0.28		
1974	1.17	0.37	0.40	
1975	0.56	0.40	0.39	
1976	0.58	0.68	0.44	0.44
1977	2.44	0.93	0.62	0.[illegible]
1978	0.61	0.84	0.82	0.[illegible]
1979	1.43	1.09	0.90	0.71
1980	2.10	1.11	1.12	1.05
1981	0.98	1.44	1.21	1.03
1982	2.25	1.54	1.14	1.14
1983	1.06	1.18	1.45	1.24

SOURCE: Tables B.1-B.3 and C.1.

TABLE C.6

ALBERTA LAGGED EXPENDITURES FINDING COSTS[a]

(EXPLORATION EXPENDITURES ONLY)
1970 - 1983
(1983 CONSTANT DOLLARS PER BARREL)

YEAR	FINDING COSTS	THREE YEAR MOVING AVG.	FIVE YEAR MOVING AVG.	SEVEN YEAR MOVING AVG.
1970				
1971				
1972	6.24			
1973	3.02			
1974	13.86	5.20		
1975	8.30	5.58		
1976	6.95	8.83	5.95	
1977	6.17	6.93	5.95	
1978	6.07	6.31	7.21	6.01
1979	13.91	8.38	8.15	7.14
1980	16.37	11.30	9.60	9.71
1981	14.84	14.99	11.00	10.32
1982	16.96	15.92	12.87	11.20
1983	16.64	15.91	15.54	12.11

SOURCE: Tables B.1-B.3 and C.7.

[a]Land expenditures and geological and geophysical expenditures lagged two years and one year, respectively.

TABLE C.7

LONG-TERM BOND/INDUSTRIALS YIELD INDEX[a]
1970-1983

Year	Index
1970	9.18
1971	8.35
1972	8.30
1973	8.47
1974	10.17
1975	10.76
1976	10.47
1977	9.71
1978	10.02
1979	10.88
1980	13.24
1981	16.22
1982	15.87
1983	12.84

SOURCE: McLeod, Young, Weir Limited.

[a]Twelve month average of McLeod, Young, Weir 40 bond long-term index/10 industrials yield index.

TABLE C.8

ALBERTA CRUDE OIL AND NATURAL GAS RESERVES REPLACEMENT COSTS
1970-1983

Year	Development Expenditures (millions 1983$)		Net Revisions and Extensions (1,000 BOE)		Development Costs (1983$/BOE)		Finding Costs (1983$/BOE)		Replacement Costs (1983$/BOE)		Finding Costs/ Replacement Costs (%)	
	Yearly	3-Year Average	Yearly	3-Year Average	Yearly	3-Year Average	Yearly	3-Year Average	Yearly	3-Year Average	Yearly	3-Year Average
1970	1,789	-	427,683	-	4.18	-	4.87	-	9.05	-	53.81	-
1971	1,900	-	491,647	-	3.86	-	4.36	-	8.22	-	53.04	-
1972	1,421	1,703	38,444	319,258	36.96	5.33	5.48	4.86	42.44	10.19	12.91	47.69
1973	1,248	1,523	332,261	287,451	3.76	5.30	2.59	3.74	6.35	9.04	40.79	41.37
1974	1,399	1,356	489,524	286,743	2.86	4.73	13.21	4.65	16.07	9.38	82.20	49.57
1975	1,445	1,364	232,087	351,291	6.23	3.88	7.11	4.96	13.34	8.84	53.30	56.11
1976	1,774	1,539	240,641	320,751	7.37	4.80	7.14	8.36	14.51	13.16	49.21	63.53
1977	1,609	1,609	813,811	428,846	1.98	3.75	9.04	7.98	11.02	11.73	82.03	68.03
1978	1,849	1,744	600,370	551,607	3.08	3.16	7.94	8.12	11.02	11.28	72.05	71.99
1979	2,180	1,879	674,791	696,324	3.23	2.70	13.55	9.91	16.78	12.61	80.75	78.59
1980	2,841	2,290	185,639	486,933	15.30	4.70	15.72	11.80	31.02	16.50	50.68	71.52
1981	2,630	2,550	300,382	386,937	8.76	6.59	9.65	12.79	18.41	19.38	52.42	66.00
1982	2,456	2,642	347,326	277,782	7.07	9.51	9.73	11.70	16.80	21.21	57.92	55.16
1983	1,801	2,296	518,010	388,573	3.48	5.91	13.03	10.46	16.51	16.37	78.92	63.90

SOURCES: (1) Tables B.1, B.2, and B.4; and (2) Canadian Petroleum Association, CPA Statistical Handbook, 1970 to 1984 editions (Calgary: Canadian Petroleum Association, 1970-1984), Section II, Tables 1, 1A, and 2, and Section IV, Tables 3-3B.

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85-1 Estimated Petroleum Finding Costs in Alberta, 1970-1983. Z. Charles Slagorsky and Janice L. Pasay. October 1985 (Price $15.00, 62 pages).

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83-1 The Alberta New Oil Royalty Formula: 74-04-01 to 82-12-31. Alan R. Webster. March 1983 (Price $6.00, 56 pages).

Presentations by Staff (available upon request)

83-1 Household Energy Costs: Recent Developments and Options for the Future. G. E. Angevine. Notes for Remarks at the "New Neighbourhood Forum," sponsored by the Ontario Ministry of Housing and Municipal Affairs, Toronto, January 31, 1983.

83-2 Net Regional and National Benefits of Canadian Electricity Exports. Gordon S. Gislason, Ellen F. Battle, and Gordon W. Douglas. Paper presented to the Canadian Electrical Association Generation System Planning and Operation Subsection, Vancouver, March 21, 1983.

83-3 Economic and Financial Implications of Lower Oil Prices. Walter Haessel. Paper presented at a conference on The Impact of Lower Oil Prices, sponsored by Data Resources of Canada, Sheraton Centre, Toronto, April 14, 1983.

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83-5 Canadian Energy Issues and Outlook. Douglas J. Haughey. Paper presented to the Institute of Internal Auditors, Calgary, October 18, 1983.

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Annual Report

Board of Directors' Report for the Year Ended March 31, 1984. ISBN 0-920522-32-7.